Economic Efficiency and Reliability Benefits of Advanced Operating Reserve Requirements

Case Study on Hawaiian Electric

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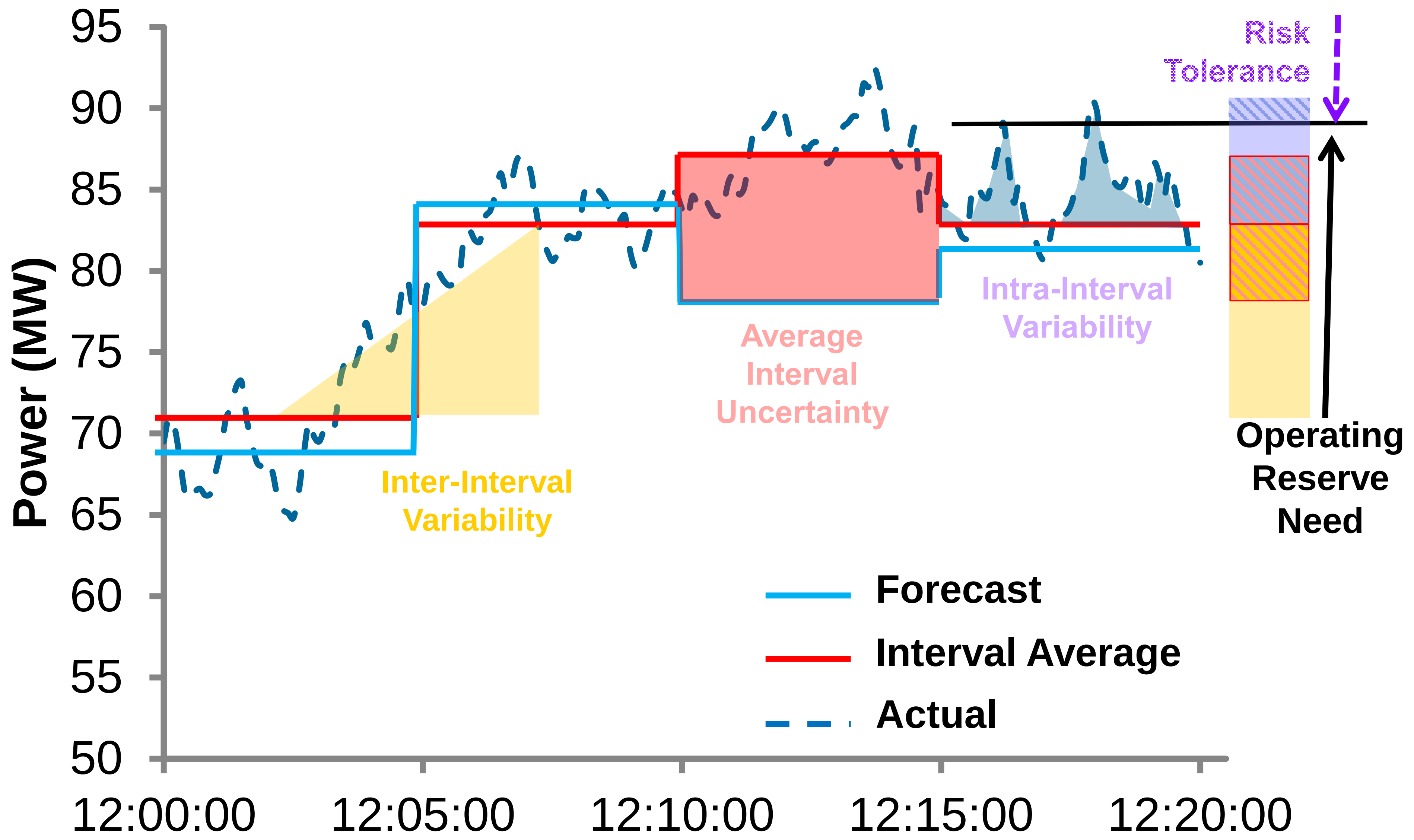
Motivation of why we are revisiting these questions

- Revisiting historical reliability standards that have been around for many years
- Variable energy resources increasing the variability and uncertainty on the system, in a way different than historical needs
- Other new technologies emerging that can either impact the need for operating reserve or support their provision
- Recent motivation toward maximizing efficiency and least-cost operations due to electricity market restructuring
- Increased software computational capabilities that can now solve difficult problems in relatively short times

Definitions (for the sake of this presentation)

- Net Load: Load minus renewables
- Energy Schedule: A level of energy that a supply resource is directed to provide at some time point in the future for some duration of time
- **Operating Reserves**: Active Power Capacity that is held above or below expected average energy schedules to respond to changing system conditions under operational time frames
  - Upward and downward response
- For multitude of reasons:
  - Maintain frequency at nominal level (60 Hz in U.S.)
  - Reduce Area Control Error (ACE) to zero
  - Assist neighboring balancing authority
  - Reduce over flow of transmission lines and transformers
  - Manage Voltage (usually done with reactive power)
  - Reduce Costs
  - Avoid infeasibilities/price spikes
  - Etc.
- Reactive Power Reserves: Mostly for voltage control (*not discussed here*)
- Planning Reserves: Long term capacity to ensure system adequacy (*not discussed here*)

Three Central Reserve Needs



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Defining Operating Reserve

	Hold	Release/Deploy
Head Room Requirement	Day-ahead commitment	Real-time dispatch
Flexibility Reserve (this study)	Day-ahead commitment	RT-dispatch
Flexibility Reserve (CAISO)	Real-time predispatch through RT-dispatch	Next RT-dispatch
Flexibility Reserve (MISO)	Day-ahead commitment through RT-dispatch	Next RT-dispatch
Regulation Reserve	RT-dispatch	AGC
Contingency Reserve	RT-dispatch	Operator action or Contingency dispatch

Dynamic Reserve Method Overview

- Method that utilizes a dynamic reserve method that attempts to **forecast** the reserve need with some level of **confidence**
- **Exact need**: Review historical data and evaluate historical need based on the **three central** reserve needs
- Determine explanatory variables that best **correlate** with need
- Requirement **combines** all needs and sources to provide a formula to determine reserve requirements based on one or more look up tables
- Choice of **confidence interval** allows user flexibility to choose risk tolerance and economic efficiency objectives of balancing area

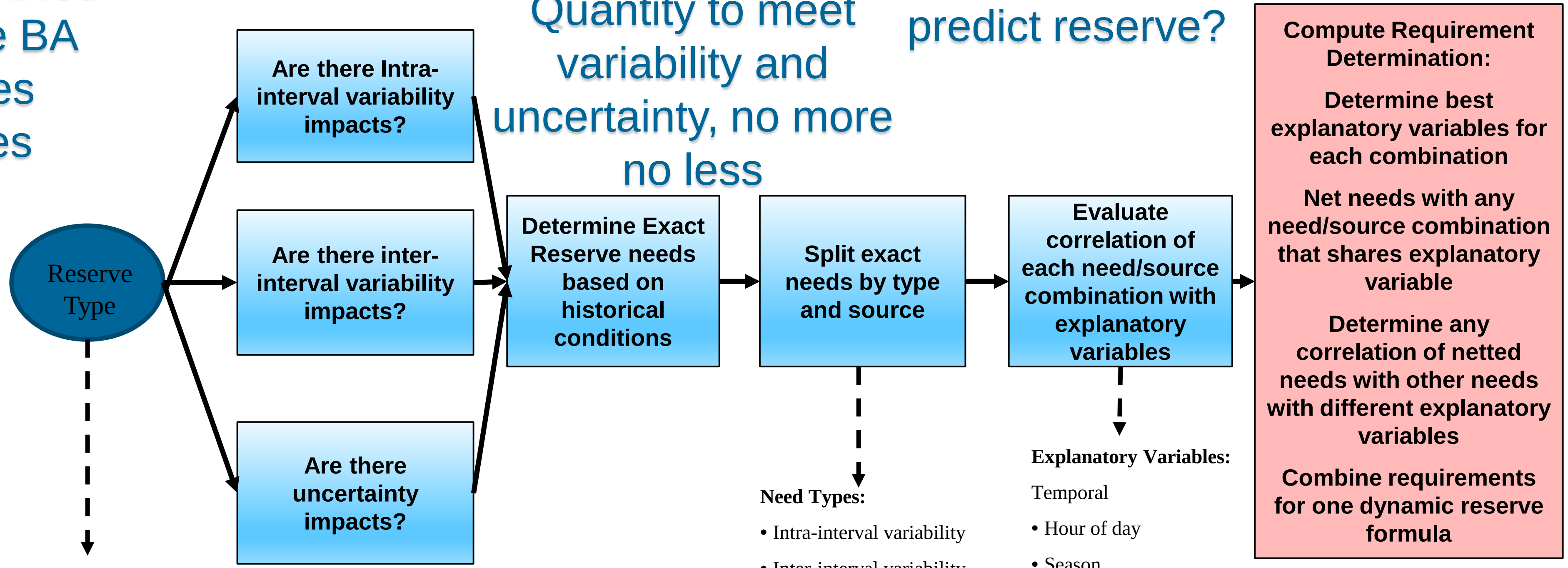
- Dynamic Assessment and Determination of Operating Reserve (**DynADOR**) Software Tool to compute reserve requirements for balancing areas

Dynamic Reserve Requirement Methodology

Reserve Defined by how the BA schedules resources

Quantity to meet variability and uncertainty, no more no less

How best to predict reserve?



Reserve Type Information:

- Scheduling Process where Reserve is held
- Scheduling Process where Reserve is released
- Reserve need met
- Direction (up/down/both)

3 Central Reserve Needs

Need Types:

- Intra-interval variability
- Inter-interval variability
- Uncertainty

Sources:

- Wind
- Solar
- Load
- Imports
- Self-schedules, start-up, shutdowns

Explanatory Variables:

Temporal

- Hour of day
- Season
- Weekday/weekend

Production-based

- Production level
- Delta production forward
- Delta production backward
- Absolute Delta

More advanced methods: multi-variable, neural networks, autogressive

Forecast for total reserve need

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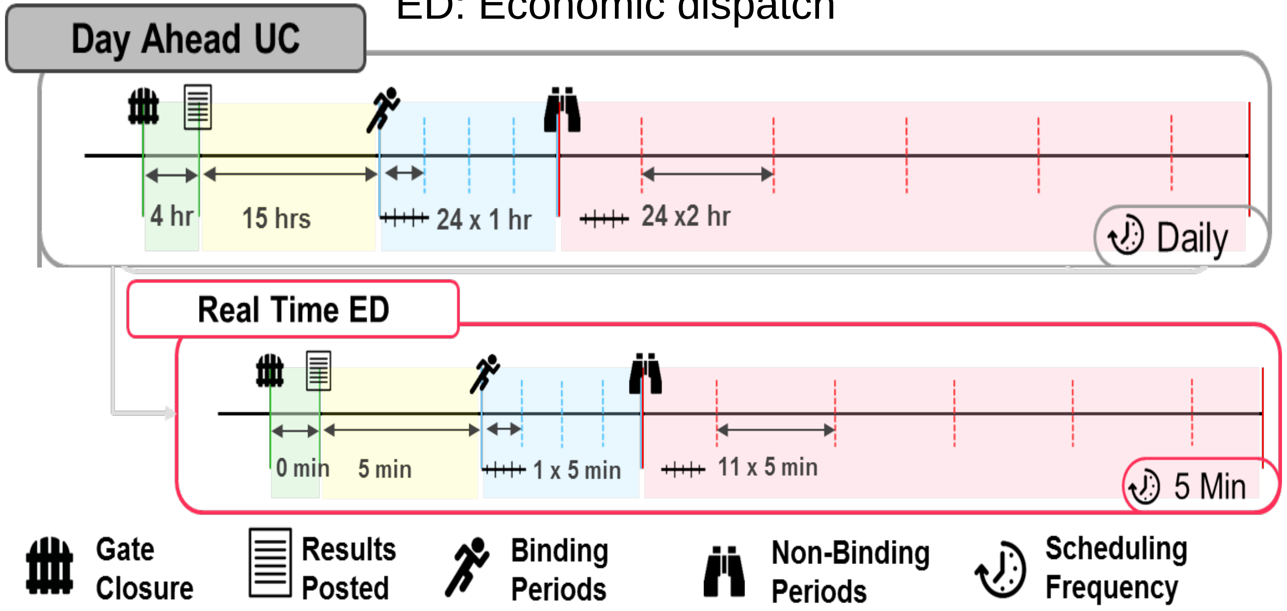
Scheduling Process for Case Studies

UC: unit commitment
ED: Economic dispatch



Hold Reserve

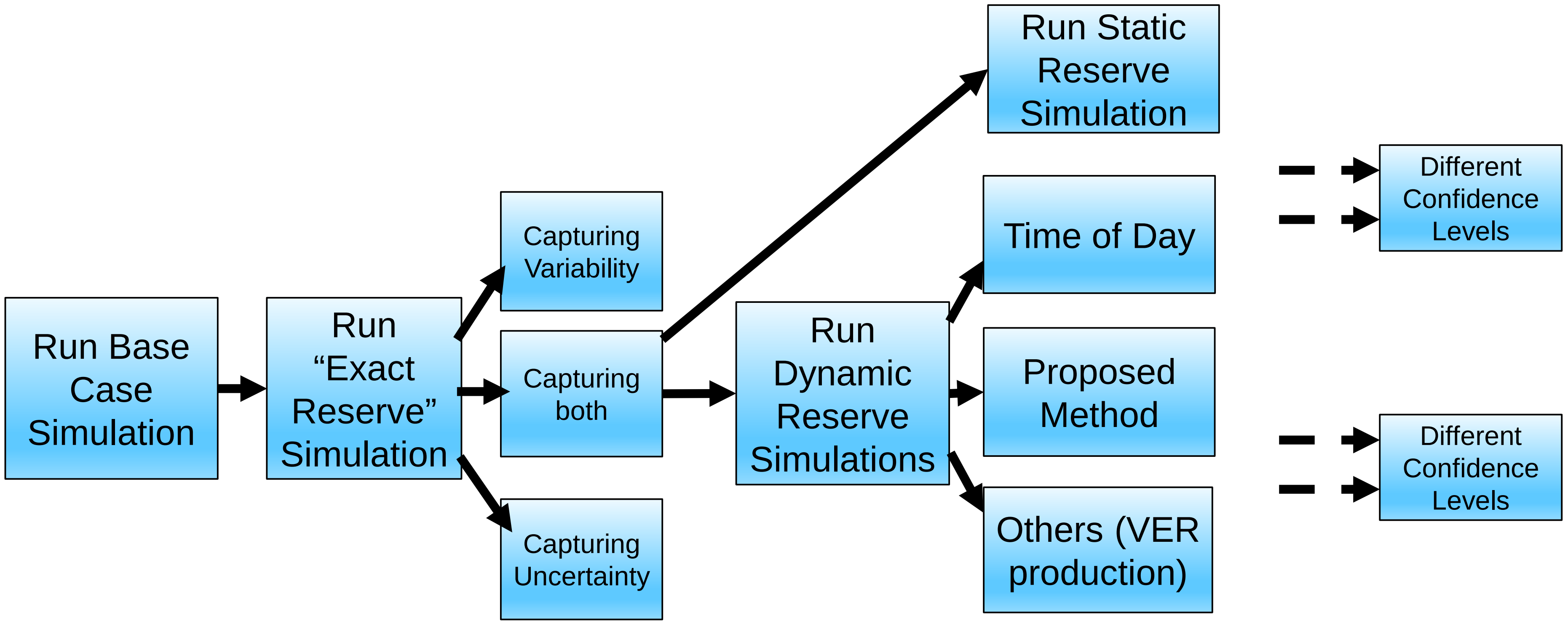
Release Reserve

In initial case studies, no units can be committed in the real-time Economic Dispatch

Variability: 5-minute max/min within 60-minute interval

Uncertainty: Forecast error between day-ahead and real-time

Study Process



How much room for improvement? What is the current state?

What is the maximum benefits can be observe from advanced reserve requirements?

What practical benefits can balancing areas expect from advanced dynamic reserve requirements? How do different Dynamic Methods Compare?

How does operator risk tolerance affect costs and reliability?

Example Combination of Needs to Determine Requirement

Wind Uncertainty Need

Wind Production	Reserve Need (multiplier)
0	0.59
42.35	0.90
84.7	0.93
127.05	0.92
169.4	0.95
211.75	0.87
254.1	0.88
296.45	0.91
338.8	0.94
381.15	0.93
423.5	0.87
465.85	0.93
508.2	0.84
550.55	0.83
592.9	0.91
635.25	0.83
677.6	0.76
719.95	0.61
762.3	0.43
804.65	0.41

Wind Variability Need

Absolute value of P(t)-P(t-1) of wind power	Reserve need (MW)
0	25.31
31.85	59.24
63.7	76.90
95.55	93.10
127.4	127.67
159.25	143.55
191.1	169.54
222.95	176.99
254.8	208.63
286.65	202.73
318.5	263.91
350.35	235.30
382.2	269.80
414.05	236.74
445.9	381.98
477.75	282.54
509.6	452.25
541.45	150.27
573.3	45.42
605.15	177.41

Load/solar Var.&Unc. Need

Hour of day	Reserve Need (MW)
0	253.587
1	186.767
2	105.5
3	48.159
4	59.237
5	155.482
6	272.777
7	482.856
8	326.674
9	218.692
10	161.407
11	165.684
12	200.067
13	239.633
14	307.825
15	249.94
16	298.355
17	314.712
18	191.929
19	289.295
20	463.521
21	542.266
22	485.006
23	373.468

Correlation wind uncertainty and wind variability = -0.14;

$$ReserveRequirement_{t\_h} = \sqrt{\sum_{n=1}^{N} f_n\left(ExVar_{t\_h}\right)^2 + 2 * \sum_{n=1}^{N} \sum_{j=1, j \neq k}^{N} \rho_{n-k} * f_n\left(ExVar_{t\_h}\right) * f_k\left(ExVar_{t\_h}\right)}$$

Test Case Study Results

	Base case	Static Rqmt 90% conf.	By VER 90% conf.	EPRI 90% conf.
Operating cost, $	531.769 M	542.222M	541.474M	539.296M
Total violations (12×MWh)	2,148,894	197,027	153,653	103,333

Significant Reliability Improvement at Modest Cost Increase

	Base case (RT Commitments)	EPRI 50% (RT Commitments)
Operating cost, $	596.536M	593.797M
Total violations (12×MWh)	114,264	31,239

Simultaneous Reliability Improvement and Cost Reduction

Benefits system dependent based on quantity of variability and uncertainty, scheduling process, decisions that can be made, and existing reserve method.

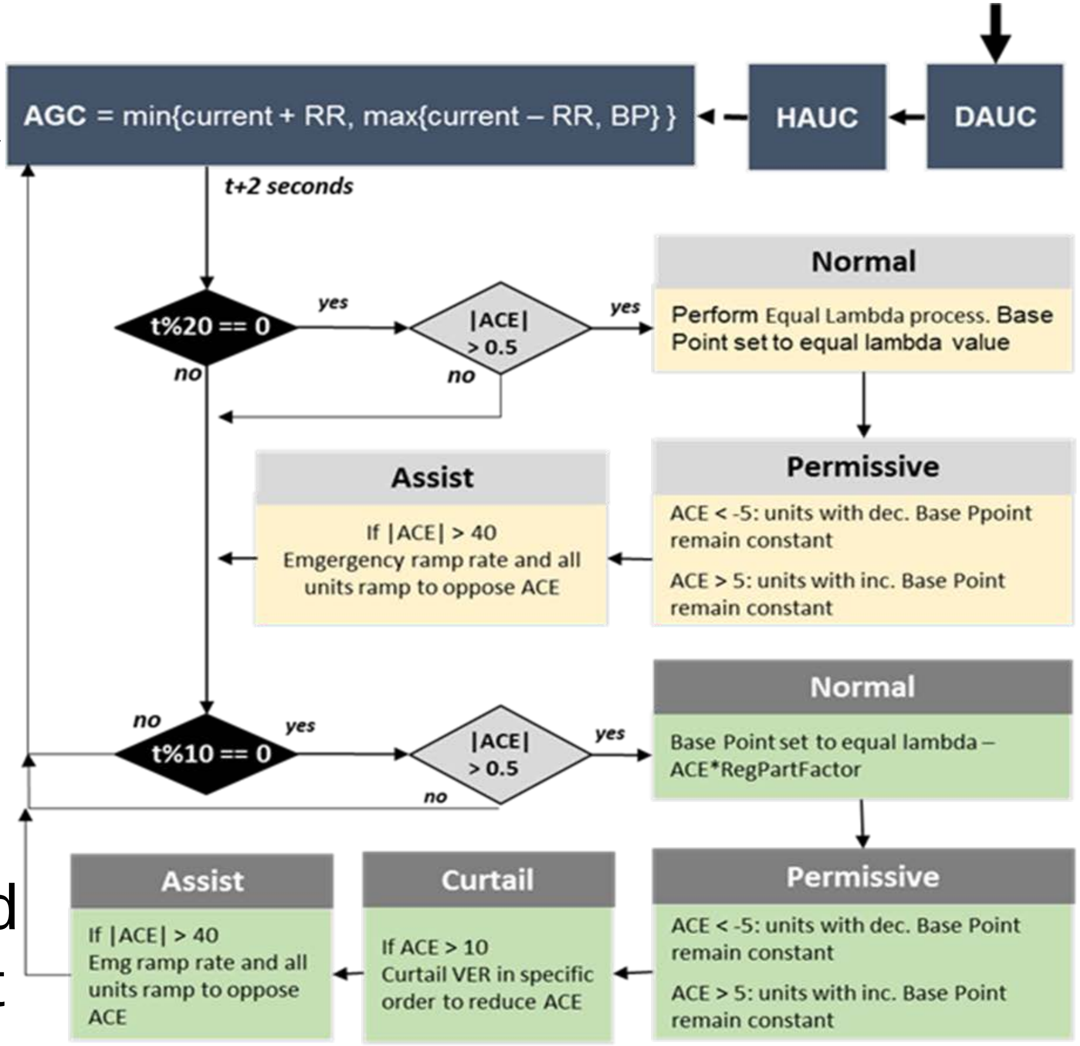
Case Study on Hawaiian Electric Company

Hawaiian Electric System Overview

- Island system
- Peak load 1150 MW
- Largest contingency 180 MW
- 98 MW utility-wind, 10 MW utility-PV, 290 MW distributed PV (at time of study)
  - Study impacts of 287MW utility-scale and 564 MW distributed PV
- Mostly low sulfur fuel oil, some diesel, 1 coal plant, small biodiesel and municipal waste
  - LSFO ~$14/MMbtu when studied
- 9 large steam units that are must run (56% of conventional capacity)
- 3 combustion turbines cycled based on load
- Commitment of CTs performed by operators, dispatch performed by AGC every 20 seconds

Scheduling Process – Unique Aspects of Hawaiian Electric Company

- UC done on hour (typically operator based)
- Economic scheduling – 20 sec basis
- Use Lambda Iteration instead of SCED-LP
- Reserve **held** hour ahead, not **released** until 20s process
- VER curtailment performed as last interconnection first



- Equal Lambda -
Simplified Description

Step 1: Choose starting lambda

Step 2: For all AGC units P=(lambda-b)/2a
Units below pmin or above pmax are fixed to those values

Step 3: Is Sum(P) minus current net load below stopping criterion (currently 1 MW), or is iteration count exceeded (currently 10)? If yes, go to Step 5. If no, go to Step 4.

Step 4: Set new lambda based on detailed algorithm. Go to Step 2 to repeat.

Step 5: If Max iteration hit and lambda is less than the minimum thermal unit inc. cost, begin to curtail VER in specific order

Step 6: Set BP equal to last determined schedules

Study Objective and Metrics

- Study the following impacts on the Oahu System
  - Impacts of higher levels of VER
  - Allowance of cycling of mid-merit plants
  - New dynamic operating reserve requirement methods
- **Production cost**: total fuel and operating costs
- **HECO Compliance Metrics**: % of time the system frequency deviation is less than +/- 50 mHz
- **Sigma ACE**: standard deviation of ACE for study period
- **Head Room Risk**: Percent of time that the system is short of sufficient head room to accommodate the loss of largest unit
- **VER Curtailment**
- Utilize simulation tool to evaluate impacts while representing the unique operating structure of HE including UC and lambda-based AGC

Reserve Requirements Comparison

All in MW	Traditional Method	Exact Method	EPRI 75	EPRI 90	EPRI 100
Average	72.7	44.3	43.9	52.4	66.1
Standard Deviation	63.2	30.3	33.8	36.2	41.3
Maximum	153.1	175.3	133.0	140.3	165.0

- Traditional: 18% of utility VER during day, 23% at night
- All methods include 180 MW of contingency reserve in addition
- EPRI NN: Dynamic reserve method based on NN percentile confidence

Hawaiian Electric Company Dynamic Reserve Study Results

Week	Reserve	Adjusted Cost ($M)	Sigma ACE (MW)	HECO Compliance (%)	Head Room Deficiency (%)
Spring A	Existing Must Run	11.913	4.95	94.3	0.0
	No Reserve	11.081	4.77	94.2	9.6
	Traditional Method	11.374	4.93	94.2	0.0
	EPRI 90%	11.281	4.87	94.3	0.0
	EPRI 75%	11.240	4.81	94.5	0.6
Spring B	Existing Must Run	13.167	4.47	95.1	0.0
	No Reserve	12.620	4.21	96.0	5.5
	Traditional Method	12.834	4.25	95.8	0.8
	EPRI 100%	12.800	4.23	95.9	0.0
	EPRI 95%	12.781	4.23	95.9	0.0
Summer A	Existing Must Run	13.578	5.18	93.6	0.0
	No Reserve	13.125	5.12	94.2	3.2
	Traditional Method	13.287	5.10	94.0	0.1
	EPRI 90%	13.241	5.07	94.1	0.0
	EPRI 75%	13.211	5.09	94.1	0.0
Summer B	Existing Must Run	13.910	3.89	96.4	0.0
	No Reserve	13.559	3.65	97.0	3.4
	Traditional Method	13.683	3.68	97.0	0.6
	EPRI 90%	13.655	3.64	97.0	0.0
	EPRI 75%	13.652	3.63	97.0	0.0

Week	Reserve	Adjusted Cost ($M)	Sigma ACE (MW)	HECO Compliance (%)	Head Room Deficiency (%)
Fall A	Existing Must Run	14.291	3.81	96.5	0.0
	No Reserve	13.967	3.62	97.0	2.1
	Traditional Method	14.095	3.60	97.0	0.0
	EPRI 90%	14.083	3.61	97.0	0.0
	EPRI 75%	14.058	3.61	97.0	0.0
Fall B	Existing Must Run	14.040	3.07	97.9	0.0
	No Reserve	13.667	2.87	98.1	3.9
	Traditional Method	13.763	2.91	98.1	1.3
	EPRI 90%	13.758	2.85	98.1	0.0
	EPRI 75%	13.748	2.85	98.2	0.0
Winter A	Existing Must Run	13.073	3.21	97.7	0.1
	No Reserve	12.506	3.02	98.1	4.9
	Traditional Method	12.658	3.09	98.0	2.0
	EPRI 90%	12.613	3.03	98.1	0.0
	EPRI 75%	12.603	3.06	98.1	0.1
Winter B	Existing Must Run	12.188	5.86	93.1	0.0
	No Reserve	11.358	5.66	93.3	11.0
	Traditional Method	11.570	5.97	93.0	0.8
	EPRI 90%	11.527	5.76	93.1	0.0
	EPRI 75%	11.515	5.69	93.5	0.5

Dynamic Reserve with 90% confidence interval allows for cycling of units with constant or improvement to reliability at $21M savings

Lower confidence interval provides greater reliability than existing methods at greater cost savings

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HE Study Recommendations and Conclusions

- Cycling of mid-merit resources for balancing can provide substantial economic benefits
  - However, other reasons for must-run status must be considered
- Combined use of cycling and advanced dynamic reserve requirements can provide economic and reliability benefits
  - **Estimated \$21-\$24M annual savings (4%) in addition to improved reliability**
  - Can allow shift to cycling of units without degradation to reliability
- VER Curtailment during high ACE required on future system
- Need to evaluate frequency responsiveness as part of reserve providers (MW/Hz and MW requirements)
- Utilize new data including probabilistic VER forecasts for reserve requirement forecast
  - Evaluating in new
- Include ramp constraints in economic AGC process
- With cycling, stagger start-up and shut-down process
- Stepped reserve demand curve for different reserve requirement confidence intervals

Summary and Next Steps

- Simultaneous reliability and economic efficiency benefits are rare to come by – makes stakeholder approval easier
- EPRI tool, Dynamic Assessment and Determination of Operating Reserve (DynADOR), takes in historical information and calculates operating reserve requirements based on user input and scheduling process parameters
  - Works for regulation reserve and load following / flexible ramping (i.e., continuous variability and uncertainty)
  - Currently not applicable to contingency reserve
- Phase II of project to implement methods in operations and include parallel operation
- Conduct studies with numerous balancing areas and ISOs to assess how much reliability and/or economic benefits may be present from moving to dynamic reserve
  - Not every system is the same – benefits depend on various factors
- Project with Department of Energy to study use of probabilistic solar forecasts in scheduling applications
- Research underway on enhancing the forecasting piece of the dynamic reserve method through more advanced methods (e.g., machine learning, multi-variate and non-linear relationships)
- Research to continue to evaluate formulation improvements to SCUC and SCED to achieve benefits in addition to dynamic reserve requirements

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